Meeting New England's Future Natural Gas Demands:

Nine Scenarios and Their Impacts

A Report to the

New England Governors

By

The Power Planning Committee
of
The New England Governors' Conference, Inc.

March 1, 2005

NEW ENGLAND GOVERNORS' CONFERENCE, INC.

POWER PLANNING COMMITTEE

The members of the Power Planning Committee are pleased to present this report to the Governors of the New England states. It represents a consensus of Committee members. Indeed, if composing a document of his or her own, there almost certainly are particular statements or findings that individual members would present differently, or not at all. Nevertheless, the members endorse the methodology used, the body of data analyzed, the comparisons of scenarios and the findings derived from those comparisons. As such, they are united in their support for this report and commend it to the Governors for careful consideration in the formulation of public policies.

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The Power Planning Committee of the New England Governors' Conference is composed of Energy Office Directors and Public Utility Commissioners of the six New England states. The Power Planning Committee appointed a Natural Gas Subcommittee to undertake this study. The Committee wishes to thank the Subcommittee members under whose direction the study was prepared.

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Executive Summary

The growing demands in New England for natural gas to fuel space heating in winter months and electric generation year round has prompted several proposals by private developers to build new liquefied natural gas (LNG) terminals here and in nearby regions. In this report, the Power Planning Committee of the New England Governors' Conference provides the Governors, at their request, with an analysis of the region's future demands for natural gas, the various resource development scenarios that might be pursued to address them and the impacts that might be expected by pursuing one or more of those scenarios.

Key Findings

- The concern for the reliability of natural gas supplies arises almost exclusively in the winter months when demand for this fuel for space heating increases dramatically and is coincident with demand from gas-fired electric generation. During the rest of the year, the region has ample delivery capabilities that can be efficiently deployed to carry additional gas supplies in the years ahead, particularly to electric power plants.

- Assuming current LNG storage and vaporization capacity remains available and usable, the region appears to have adequate delivery infrastructure to meet winter peak gas demands through 2010, under both normal and high estimates of growth in gas demand. However, if current LNG storage and vaporization were unavailable during winter months, reliability problems would be felt immediately.

- To ensure reliable delivery of natural gas in the winters beyond 2010, the region must accomplish a substantial amount of demand reduction or infrastructure development before that time. Since many of these developments will require several years of program expansion or facilities permitting and construction, state policies to encourage and develop these initiatives need to be implemented in the very near future.

- Various demand reductions or resource development scenarios are available to be pursued, each providing a different degree of success in achieving energy policy and other public policy goals. Some of these scenarios can only be accomplished with new public mandates and additional financial support while others may be accomplished by privately financed, market-based developments which government must regulate, but cannot prescribe.

- We find that expansion of fuel switching, energy efficiency and renewable energy programs may be the least expensive ways to improve gas supply reliability while improving fuel diversity. On the other hand, expansion of LNG delivery and storage terminals provide considerably greater improvements to gas supply reliability than those scenarios.

- Expanded investments in <u>gas</u> energy efficiency programs may yield even greater reliability enhancements and even lower overall costs than most other scenarios. To confirm this expectation, however, considerably more information on the costs and performance of these programs would be needed.

Growing Demand for Natural Gas and Reliability Concerns

Estimates from various sources all agree that the portion of our electric generation that uses natural gas as a primary fuel, on an annual average basis, has rapidly grown over the past few years and is likely to continue to grow. However, during a peak winter day, space heating accounts for a large majority of gas demand. The natural gas that is delivered by gas utilities for space heating is protected by "firm" delivery contracts, whereas natural gas used for electric generation is largely delivered under contracts that allow generators to take gas only after firm customers have been served. It is also important to bear in mind that the region has substantial underutilized gas delivery capacity between April and November each year. The use of this capacity to deliver gas for electric power is highly efficient. Gas capacity and reliability concerns are mainly prevalent in the winter months.

Overall, we find that regional demand for natural gas is growing, though not as fast as some forecasters have suggested. In general, we find that our existing gas delivery infrastructure (pipelines and storage mechanisms), should be able to meet winter time peak day demands for gas for space heating and electric generation through 2010. However, this is the case only if the region has continued use of the LNG delivery terminal in Everett, MA and the 31 satellite LNG facilities located around the region. Those facilities must have sufficient LNG in storage and be able to turn it into gas vapor and inject it into the local distribution systems on those peak demand days. In an extreme case, if LNG from these facilities were not available on a peak day (e.g. because extremely cold weather for many days in a row had drained them down), then the region could well have insufficient gas supply to meet the needs of all customers for space heating and some key electric generators.

Even assuming this LNG storage and vaporization capability remains available, if gas demand grows at a rate equal to or higher than recent growth rates, the region's gas delivery infrastructure would be insufficient to deliver all needed gas after 2010. Under these conditions, to avoid leaving some customers without space heat in 2010 and after, additional gas supply infrastructure (either expanded pipeline capacity or expanded LNG storage capacity) or resources that reduce gas demand would have to have been added to the system.

Beyond the ability of infrastructure to deliver gas supplies, sound energy policies also should contribute to achieving the lowest possible long run average price for the fuel and to maintaining as much stability as possible in the short-term price of that fuel. We also must be concerned with the environmental and societal impacts of various fuel use scenarios.

Resource Development and Demand Reduction Scenarios

In this report, we examine several scenarios that might be pursued to address the goals of reliability of supply, price moderation and other impacts. We find that the reliability of the fuel supply, particularly on the coldest winter days, could be addressed through actions that increase our capacity to store LNG in the region. However, to the extent that this would depend on increasing the delivery of LNG, still in its liquid form, to on-shore terminals for storage (or for trucking to expanded satellite storage facilities), we recognize the concerns for safety and security of populations that live and work in the vicinity of LNG delivery terminals. Therefore, in order to compare the costs and risks of siting LNG terminals in the region with alternatives, we examine other resource development scenarios to determine whether they are feasible and at what cost they might be pursued. These scenarios include the delivery of additional gas vapor to the region from LNG terminals located on land but outside the region, the delivery of added vapor to the region from off-shore LNG unloading facilities, the significant expansion of indigenous, renewable power generation facilities and the expansion of electric energy efficiency programs that might reduce demand for natural gas.

In all, we compare nine resource development and demand reduction scenarios to identify those that are likely to be most successful in meeting the region's energy policy goals. We consider their relative contributions to gas supply reliability, fuel diversity, price mitigation and stabilization, security of the gas supply, and finally their estimated costs for delivery or displacement of gas.

In addition to these policy objectives, environmental protection must also be considered in the formulation of energy policy. The policy objectives of increasing environmental protection and promoting public health can only be met by taking these impacts into account in evaluating the various resource scenarios for meeting the region's energy needs. The goal of identifying a dependable, affordable, environmentally sound energy policy cannot be achieved without this analysis.

Increasing Reliability

The largest contributions to increasing gas supply reliability come from the LNG scenarios both individually and as a group. Among these, the greatest contribution is made by the on-shore, in region LNG facilities, as illustrated by Weaver's Cove and KeySpan. Contributions from the off-shore and out-of-region LNG scenarios are slightly less but still very substantial when compared to fuel switching, electric energy efficiency, and renewable generation as well as coal gasification and nuclear generation.

Another measure of the reliability enhancements of the various scenarios is the time required to realize benefits, and the relative size of those benefits year to year. Fuel switching, energy efficiency and renewable generation potentially can be initiated promptly as a result of government mandates or funding programs. Among these three, by far the largest contribution to gas supply reliability is made by fuel switching. LNG scenarios are assumed to take at least two years longer than fuel switching, due to the lead time for construction, before they begin to produce contributions to improving gas supply reliability, though their contributions are all substantially greater than those of fuel switching, energy efficiency, and renewable generation. The coal gasification and nuclear generation scenarios have much longer lead times and therefore do not begin to deliver contributions to improving gas reserve margins until much later and their contributions are significantly smaller than the LNG scenarios.

Increasing Fuel Diversity

The goal of fuel diversity is best achieved by the electric energy efficiency scenario as well as by the three power generations scenarios that use fuels other than natural gas during peak demand periods: renewables, coal gasification and nuclear generation. In addition, the on-shore, LNG storage scenario provides equally good fuel diversity because it provides additional storage for a system that is critically dependent on storage to meet peak day gas demands. The other LNG scenarios, because they provide additional gas vapor but no LNG storage capability, are not as effective at meeting fuel diversity goals. However, all the LNG scenarios contribute substantially to improving the region's fuel supply diversity to some degree because they can provide fuel from a different part of the world than the source of most of our current pipeline gas supplies.

Mitigating and Stabilizing Prices

Price-related impacts of LNG scenarios will depend on the contracts underlying the development and the level of out-of-region demands for LNG shipments. If out-of-region demand is strong and LNG cargoes are priced according to spot or index prices, then there will be few benefits of this scenario in terms of lower and/or more stable prices. On the other hand, if LNG terminal operators are able to secure long-term contracts at prices lower than pipeline-delivered prices and pass these terms along to customers, then the region will enjoy some price mitigation and more stable prices.

Security Concerns

In terms of public safety, the least security concerns arise with energy efficiency, renewables and coal gasification. Scenarios that involve the delivery and storage of LNG pose the greatest security threats, especially if the location of the facility is near densely populated areas. Recent studies indicate that the risk of an uncontrolled release occurring during the delivery or storage of LNG is low, especially given the security measures now taken during the delivery of LNG to on-shore terminals. It appears that the consequences would be similar to those that would occur if a tanker full of gasoline were similarly breached and ignited.

Public concerns with the potentially serious consequences of a LNG accident tend to obscure technical assessments that the risk of such an incident is low. Regulators must ensure these concerns are addressed when evaluating the relative merits of alternative LNG delivery and storage scenarios.

Cost Impacts

We compare the relative cost of the scenarios on the basis of the cost incurred to provide additional or displace expected gas supplies. Fuel switching by gas-fired power generation capacity to burning oil at peak gas demand periods is estimated to be the least cost scenario. Electric energy efficiency expansion is the next least costly scenario. (We would expect gas energy efficiency, if implemented on the ambitious scale as that contemplated under the electric efficiency scenario to be at least as cost effective if not more so.)

Additions of new coal gasified electric generation and new nuclear generation are next most costly, followed by expanded renewable electric generation. These indicate that trying to reduce gas consumption through increased electric generation using other fuels is a more expensive proposition than demand reduction.

The expanded LNG scenarios are the most expensive of all, not because of their capital costs (which are relatively modest compared to the other scenarios) but mainly because the cost of natural gas is so high relative to other fuels.

Government–Based and Market-Based Initiatives

It is important to note that further development of LNG storage is a scenario that must be initiated by private investors proposing specific projects in specific locations. While government does not dictate to developers the exact locations, these projects would be subject to government permitting, monitoring, and safety regulations. Through its regulatory powers, state government can seek to mitigate unwanted impacts from LNG options, but cannot require the developers to move the proposed location of the project. The advantage of such market-based projects is that, if they are not needed or otherwise prove uneconomic, consumers are not saddled with the burden of paying for them. Private capital put at risk is the responsibility of equity shareholders and lenders. Even when they succeed, these projects deliver benefits to consumers at prices dictated by market forces, not by government.

On the other hand, development of energy efficiency and renewable power generation are activities that depend heavily on government initiative and can be strongly influenced by government policies, at least in terms of acceptable technologies, development time and size of facilities. These are also developments that have shorter lead times and involve fewer irrevocable commitments of resources rather than large, lumpy, capital-intensive projects. At the same time, they require government to take responsibility for the cost-effectiveness of these policies. Whether or not they accomplish their intended goals, gas and electricity consumers must pay for them.

The Power Planning Committee hopes this report helps the New England Governors evaluate their strategic and resource options and chart a course for the future that will best serve the interest of all citizens in the region.

Chapter 1: Introduction and Study Purpose

The Power Planning Committee is composed of Directors/Commissioners of the six New England Energy Offices and Public Utilities Commissions. It was established by the New England Governors' Conference (NEGC) to monitor and act on energy concerns in the region. Last fall, the New England Governors passed a resolution requesting that the Power Planning Committee provide them with a comprehensive assessment of New England's current and forecasted use of natural gas and liquefied natural gas (LNG). Primarily, the Governors wanted the information so that they could better respond to competitive suppliers' proposals to develop additional LNG delivery and regasification terminals in or near New England. The assessment was not to take positions in support or opposition to particular proposed LNG terminals. The Governors will consider the report's findings at their March 2005 meeting in Washington, D.C.

Background and the New England Governors' Resolution

Natural gas is a major and growing source of energy throughout the United States; in New England it accounts for 18% of the region's total energy consumption and approximately 40% of the fuel used to generate electricity in 2003. The majority of new electric generation capacity in the region since 1999 (almost 10,000 MWs) has been gas-fired. Natural gas is projected to be a large portion of the regional fuels used to generate electricity because of its positive environmental characteristics relative to other fossil fuels and the ease of siting gas-powered generating plants. In New England, LNG currently plays a vital role in meeting this region's winter time space heating needs. In fact, Massachusetts has one LNG delivery and regasification terminal[1] that serves as a critical link in the region's energy infrastructure and supplies 20% of the region's annual natural gas.

The growth of natural gas use for power generation in New England, however, places additional demand on the region's current ability to supply, transport, and store this fuel during the peak heating season. A recent example of this occurred in mid-January 2004. Unusually severe weather in New England stressed the capability of the region's natural gas and electricity infrastructure. Space heating and electric generation competed for natural gas supplies. As a result, prices of natural gas spiked and electric reliability was tested as natural gas supplies tightened, thereby causing gas-fired plants to become unavailable. In addition, according to the National Petroleum Council Report of September 2003, "North America is moving to a period in its history in which it will no longer be self-reliant in meeting its growing natural gas need...." This begs questions about how New England will maintain and even gain new supplies of natural gas. In order to meet future gas needs, several companies have proposed to build additional LNG sites in New England and eastern Canada.

The projections of increasing natural gas demand and the proposals to meet increasing demand through the development of new LNG facilities have raised important issues for the New England Governors. Clearly, an adequate and reliable natural gas supply and delivery infrastructure is critical to the safety, security, and economic well-being of the New England region. Yet the proposed development of new LNG facilities to meet New England's growing energy requirements raises questions about safety and security issues.

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[1] Distrigas

As a result, the New England Governors assigned two tasks to the Power Planning Committee. These tasks are spelled out in the Resolution entitled, *"A Resolution on the Use of Natural Gas to Generate Electricity in New England."*[2]

1. Analyze current and projected use of natural gas and LNG and identify any actions that should betaken to strengthen the region's energy and fuel diversity position in light of projected developments in the electricity market; and

2. Report its findings and any actions it recommends be taken by the Governors or others to strengthen the region's energy position with respect to the use of natural gas, LNG, and other options to meet its energy needs.

Report Approach

To undertake the work, the Power Planning Committee formed a Natural Gas subcommittee. This group consisted of Commissioners/Directors and staff of the Massachusetts Division of Energy Resources, and the Massachusetts Department of Telecommunications and Energy; the Maine Office of Energy Independence and Security; and the Rhode Island State Energy Office and Rhode Island Public Utilities Commission.

The October 2004 to February 2005 timeframe for conducting the assessment was extremely brief. Therefore, the Natural Gas subcommittee agreed that the best approach was to examine existing data and evaluate publicly available forecasts of natural gas demand. In particular, the Natural Gas subcommittee's work was to analyze certain issues on LNG and the natural gas markets in New England to assist the Governors with answers to the following questions:

1. What are the underlying forces causing increased use of natural gas?

2. What will the impacts of increased competition for natural gas supplies be among consuming sectors if natural gas supplies remain tight in the winter, particularly between the space heating customers and electric generation markets?

3. What new infrastructure expansions have been proposed to meet growing natural gas demand in New England?

4. What role can and should LNG play in meeting natural gas supplies for electricity demand?

5. How will increased demand for natural gas by electric generators alter the regional fuel mix for electricity generation? What options are available to address concerns over New England's growing dependence on natural gas, and the loss of fuel diversity, in the electric generation sector? and,

6. What supply-side and demand-side options other than natural gas and LNG-fired generators are available to meet projected electricity demand?

[2] See Appendix A.

Report Outline

The next chapter provides an overview of New England's natural gas system. It reviews the region's natural gas use, primarily concentrating on the distinctions among the consuming sectors. It also shows a profile of New England's natural gas supply infrastructure, including interstate pipelines and local natural gas storage facilities. The analysis in this chapter identifies that in the winter, there is little margin between natural gas demand and system capacity limitations.

Chapter 3 examines New England's natural gas demand outlook for the electric generating sector and non-generator sectors. Underlying forces causing increased annual and peak day natural gas demand are reviewed. This chapter then compares the demand forecast to gas supply capacity, considering existing capacity levels and a few additions already under construction. Chapter 3 concludes with projections of New England's capacity reserve margin and discusses national natural gas demand and supply forecasts which could impact the region's reserve margins.

Chapter 4 discusses policy issues and objectives related to natural gas price moderation, price stabilization, fuel diversity in electric generation, improved security of supplies, and improved reliability of supplies. The chapter evaluates the extent that different options for supplying New England's future natural gas demand meet these policy objectives.

Chapter 5 provides a comparison of the resource development scenarios according to their contributions to the policy objectives discussed in Chapter 4.

Chapter 2: New England Natural Gas Overview

Physical Structure of the Natural Gas System

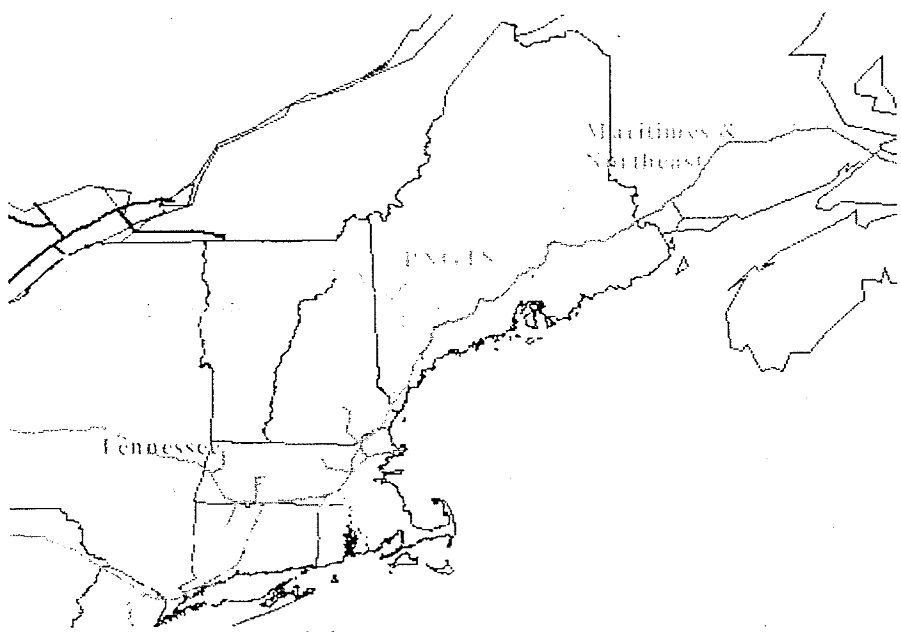
New England receives about 80% of its natural gas supplies from North American supply basins in the U.S. Gulf Coast, western Canada, and eastern Canada (Sable Island offshore) via interstate pipelines.[3] In addition to pipeline gas, liquefied natural gas (LNG) is an integral part of the gas supply portfolio and is imported into the region through the Distrigas facility in Everett, MA.

1. Pipeline Delivery System

As shown in Figure 2-1, the interstate pipeline companies serving New England are: Algonquin Gas Transmission, Iroquois Gas Transmission System, Maritimes and Northeast Pipeline, Portland Natural Gas Pipeline System (PNGTS), and Tennessee Gas Pipeline Company.[4] The majority of New England's natural gas is delivered by the Algonquin and Tennessee systems. Together these two systems comprise over 80% of the region's pipeline deliverability in 2003.[5]

Figure 2-1

New England Interstate Natural Gas Transmission System



Source: Northeast Gas Association

[3] Northeast Gas Association, "2004 Statistical Guide," Sept. 2004.
[4] Vermont Gas has 300 miles of intrastate pipeline through Vermont. It receives gas from TransCanada pipeline at Highgate on the VT/Canadian border. Granite State Gas Transmission has a pipeline extending from the MA-NH border through the NH coastal area to Portland, ME, but is has no direct import capacity. Federal Energy Regulatory Commission (FERC), "New England Gas Infrastructure Report," Dec. 2003.
[5] Northeast Gas Association, "2004 Statistical Guide," Sept. 2004.

Supplies delivered by the Algonquin and Tennessee pipelines originate in the U.S. Gulf Coast, while Iroquois and PNGTS transport Western Canadian gas, and Maritimes and Northeast carries Eastern Canadian gas. During the last decade, New England added three of the pipeline systems delivering gas from Canada – Iroquois in 1992, Portland in 1999, and Maritimes and Northeast in 2000.

2. *Natural Gas Storage*

Stored natural gas is a critical economic and engineering component of the region's natural gas delivery system. Were it not for gas storage, our economy would be constrained by the willingness of the market to invest in expansion of pipeline capacity to meet both long-term demand growth and day-to-day demand fluctuations. Thus, natural gas storage bolsters system reliability by allowing for an economic means to meet winter peak demand requirements by maintaining vital pressure in the pipeline system.[6] Storage also contributes to the diversity of the regional gas supply portfolio and reduces our reliance on the availability and price-competitiveness of any individual supply source.

In the past, the use of natural gas in New England was limited to the volume of natural gas that could be delivered to the region by interstate pipeline. New England's native geology does not allow for the development of underground storage caverns that other parts of the country have, where gas is stored in vapor form, mainly in depleted gas and oil wells and salt caverns. Therefore, the only viable means to store gas in New England is in liquid form. In the 1950's, gas companies began to rely on liquefying pipeline gas to obtain storage supplies. In 1971, Distrigas began importing LNG into New England by ocean-going tankers for additional supplies. At first, the LNG was used as a peaking service, but now is injected into the system year-round.

Currently, LNG meets approximately 20% of New England's annual gas demand. In periods of winter peak demand, LNG supplies well over 30% of New England's natural gas needs. Table 2-1 indicates the contribution of LNG to peak-day fuel requirements of 6 major regional gas distribution companies, helps to illustrate the industry's dependence on LNG storage capabilities across the region.[7]

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[6] Adequate pipeline pressure is vital to maintaining gas flow and thus avoiding loss of gas and customer service disruption. Unlike an electricity outage, a gas outage would require that a trained person enter customers' homes and physically light the gas pilots on affected appliances. If a widespread outage were to occur during harsh winter weather, it would present an enormous public health and safety concern.

[7] The terms "peak day design" and "design day" are defined later in this paper but, as used in this table, peak day design relates to the design of the distribution companies' gas supply portfolios to meet potential demand levels.

Table 2-1
LNG as Percent of Peak Day Design

COMPANY	LNG as Percent of PEAK DAY DESIGN
Bay State Gas	23%
CT Natural Gas	30%
KeySpan	36%
NE Gas Co.	38%
NSTAR	44%
Southern CT Gas	23%

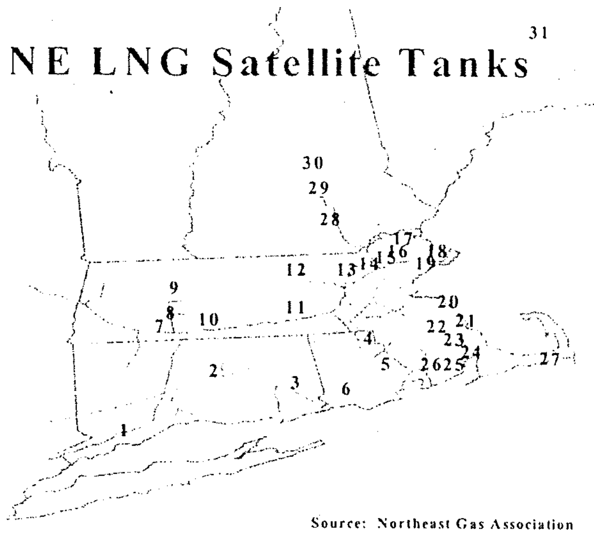
Source: Northeast Gas Association; Data for winter 2003-2004

The New England region has LNG storage facilities in 5 states (31 communities) in 46 storage tanks at key points in Local Distribution Companies' (LDCs) service territories (see Figure 2-2). The LNG is supplied by truck deliveries from the Distrigas facility. The LDCs' combined LNG storage capacity is 15 billion cubic feet (Bcf) (which, for the sake of perspective only, is on the order of 3% of their annual sales).[8] Total daily vaporization capacity at LDC-owned storage facilities is almost 1.3 Bcf/d, or about 35% of their peak day sales. This means LDCs, collectively, have the capacity to hold just over 10 days of winter peak demand volumes. Distrigas is capable of loading 100 Mcf/day to trucks with its four loading bays. In 2003, Distrigas trucked about 14 Bcf[9] of LNG to the satellite LDC facilities. The LDCs' storage tanks are generally refilled in the summer, after winter depletion.

With regard to LNG's contribution to system pressurization requirements, Distrigas' vaporization service helps to maintain needed pipeline pressure in combination with LNG satellite storage facilities. Distrigas maintains a direct connection with the high-pressure Tennessee Gas Pipeline and medium-pressure Algonquin Pipeline. If a pipeline compression station suddenly failed, Distrigas could inject gas into the system to help maintain necessary pressure levels and avoid service disruption. Additionally, Distrigas maintains a direct connection to KeySpan's distribution pipeline. Current total storage capacity in the two tanks located at Distrigas' terminal is approximately 3.5 Bcf. In 2003, Distrigas received 158 Bcf [10] of LNG at the terminal, all from Trinidad and Tobago. During that year, Distrigas received, on average, a shipload of LNG every 5-6 days, approximating 60 ships in the year.[11] Distrigas' current physical capacity can accommodate up to about 98 cargo receipts annually. Approximately 6-8%[12] of Distrigas' annual LNG receipts is distributed to 31 satellite storage tank locations throughout New England.

[8] LDC sales are 57% of regional gas consumption. 15/0.57x800 = 3%.
[9] FERC and the U.S. DOE's Office of Fossil Energy.
[10] Northeast Gas Association, "2004 Statistical Guide," Sept. 2004.
[11] FERC and the U.S. DOE's Office of Fossil Energy.
[12] FERC and the U.S. DOE's Office of Fossil Energy.

Figure 2-2



LNG Safety and Security

Safety and security issues surrounding LNG deliveries have received significant public attention, particularly in the wake of September 11, 2001 terrorist attacks. It is important to recognize a common public perception of the elevated risk of consequences resulting from breach of an LNG tanker.

LNG ships are designed with double hulls for protection against spills and carry sophisticated fire-fighting equipment. The U.S. Coast Guard mandates safety zones around LNG tankers and escorts them through harbors to ensure safe passage. LNG facilities also have systems and equipment to prevent and contain LNG spills. Since September 11, 2001, the LNG industry, in cooperation with federal and local authorities, has further strengthened safety and security provisions surrounding LNG deliveries and at storage terminals.

In December 2004, the Sandia National Laboratories issued a report on the risks and safety implications of an LNG spill over water (the "Sandia Report").[13] That report found that risks of accidental LNG spills, such as from collisions and groundings, are small and manageable under existing safety policies and practices. Such practices include operation and safety management, improved modeling and analysis, improvements in ship and security system inspections, establishment and maintenance of safety zones, and advances in future LNG off-loading technologies.

The Sandia Report further determined that risks from intentional events, such as acts of terrorism, can be significantly reduced with appropriate security, planning, prevention, and mitigation. While finding that the consequences from an intentional breach can be more severe than those from

[13] Sandia National Laboratories, "Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water," Dec. 2004.

accidental breaches, multiple techniques exist to enhance LNG spill safety and security management and to reduce the potential of a large LNG spill due to intentional threats.[14]

Nevertheless, the Sandia Report determined that in the event of a fire due to an LNG spill, the most significant impacts to public safety and property would exist within approximately 250 to 500 meters (0.16 to 0.31 miles) of a spill, with much lower impacts at distances beyond 1600 meters (about 1 mile). The report mentions that an LNG fire can damage or significantly disrupt critical infrastructure located within so-called Zone 1 areas – where LNG shipments transit narrow bridges or channels, pass under major bridges or over tunnels, or come within approximately 250 meters (820 feet) of people and major infrastructure elements, such as chemical plants, military facilities, population and commercial centers, or national icons.[15]

Public concerns with the potentially serious consequences of a LNG accident tend to obscure technical assessments that the risk of such an incident is low. Regulators must ensure these concerns are addressed when evaluating the relative merits of alternative LNG delivery and storage scenarios.

Natural Gas Demand Has Grown Rapidly, Especially for Electric Generation

In New England, natural gas demand is currently at about 800 Bcf per year.[16] Demand has risen rapidly since 1990 (13% of regional energy consumption in 1990[17] vs. 18% in 2003[18]). There are approximately 2.3 million natural gas customers in New England. Residential customers number 2.1 million; commercial and industrial customers number approximately 243,000.[19] For New England, gas consumption on an annual basis by sector for the year 2003 was residential, 23%; commercial, 17%; industrial; 17%; and power generation, 43%.[20] The growth of natural gas use in power generation is driven by the environmental benefits of natural gas over other fossil fuels and ease of siting of natural gas generation. For the same reasons, natural gas continues to be an important fuel in the residential, commercial, and industrial markets.

The majority (almost 10,000 MWs) of new electric generation capacity built in New England since 1999 burns natural gas as its primary fuel, as shown in Figure 2-3. Natural gas is now the largest component of the regional power generation fuel portfolio.

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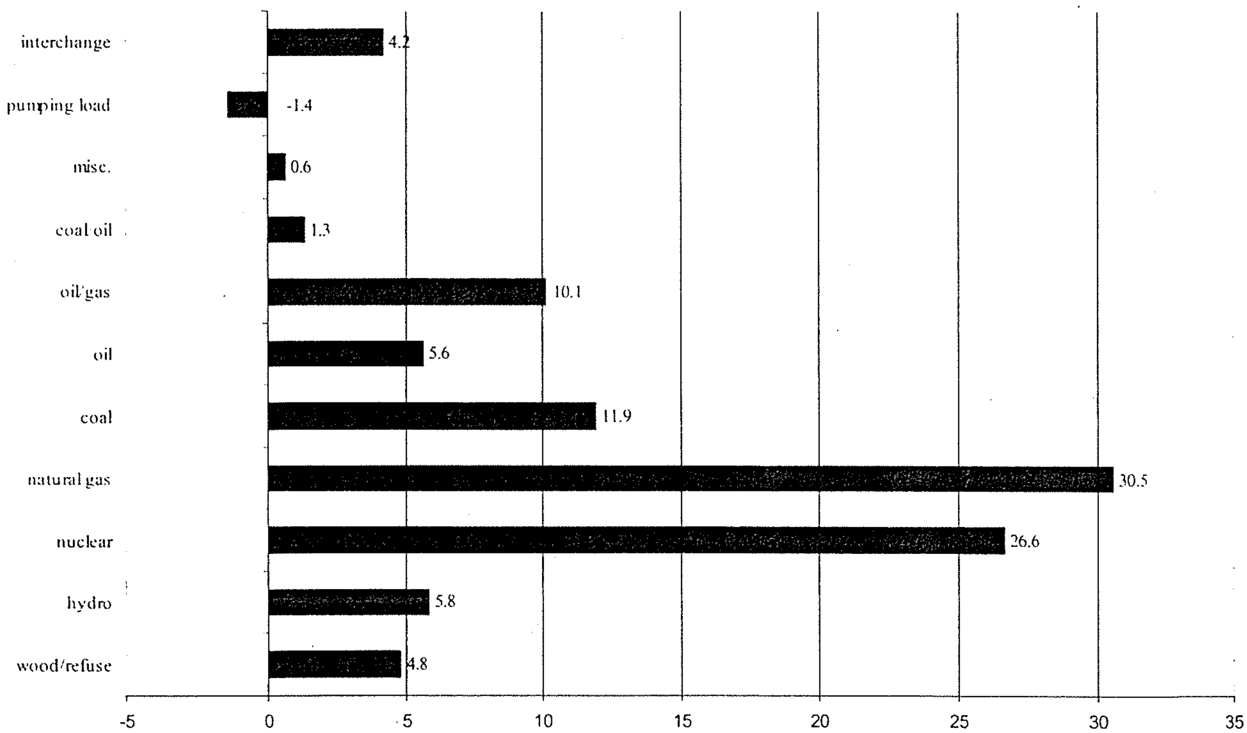
[14] Sandia Report, page 14.
[15] Sandia Report, pgs. 15, 19, and 20.
[16] Northeast Gas Association, "2004 Statistical Guide," Sept. 2004.
[17] U.S. DOE/ Energy Information Administration, "State Energy Data Report 1999," May 2001.
[18] FERC, "New England Gas Infrastructure Report," Dec. 2003.
[19] Northeast Gas Association, "2004 Statistical Guide," Sept. 2004.
[20] Northeast Gas Association, "2004 Statistical Guide," Sept. 2004.

Figure 2-3

2003 Total Electric Generation by Energy Source, Percentage (%)



Source: ISO-NE

Most of the new gas-fired electric power generators in New England are connected directly to the interstate pipelines. This is due to the fact that natural gas-fired electric generation stations require substantial amounts of gas at pressures that are normally above LDCs' system design specifications. The LDC system typically operates at a base gas pressure level of 150 psig, which is much lower than the 400-650 psig pressure levels required by a typical combined cycle power plant.[21]

Additionally, Distrigas is directly connected by pipeline to the 1,500 MW Mystic (units 8 & 9) power plant and is its sole fuel supplier.[22] Mystic electric generation plant, the largest in New England, is currently critical to electric reliability in the Northeastern Massachusetts/Greater Boston (NEMA) area. Today, the NEMA area does not have enough installed generation within the area to meet its peak electricity demand and therefore must import power from other parts of New England via transmission lines. Furthermore, the NEMA electrical zone contains several generating units slated for retirement and/or deactivation over the next few years.

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[21] PSIG is pounds per square inch of gas.

[22] Mystic plant refers to units 8 and 9, Summer Maximum Capacity is 1398.26 MW; Winter Maximum Capacity is 1695.78 MW. ISO-NE, "NEPOOL 2004-2013 Forecast Report of Capacity, Energy, Loads and Transmission (2004 CELT Report), April 2004.

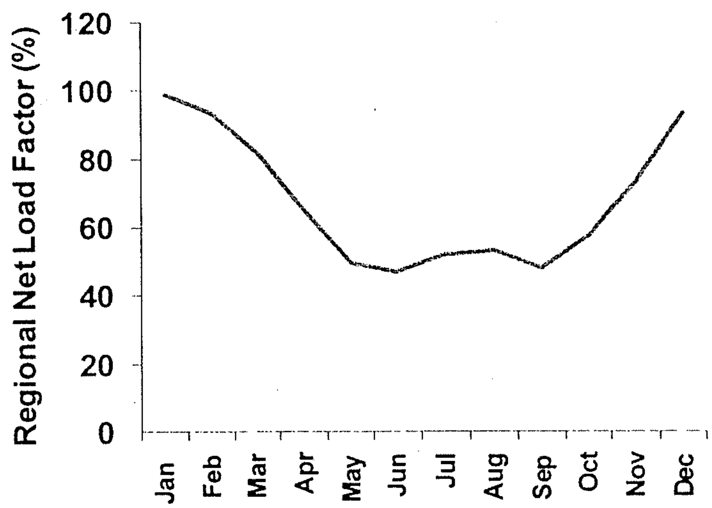
The Independent System Operator of New England (ISO-NE) recently released its Regional Transmission Expansion Plan (RTEP04), which includes a detailed capacity availability projection for the NEMA area. In the summer of 2005, the projected electrical demand requirement for the NEMA zone is 6,475 MWs, including the high load forecast and reserve requirement. The total net installed capacity in NEMA, accounting for assumed unit outages of 326 MWs, is 3,276 MWs, and the import capability is approximately 3,600 MWs. Thus, the total available resource capacity in NEMA is approximately 6,876 MWs, a 6.2% surplus margin. Accounting for the Kendall Station unit retirements recently approved by ISO-NE, the NEMA available surplus margin falls to 3.3%. ISO-NE projects that the capacity surplus will increase 900 MW when NSTAR places a new 345 KV transmission line into commercial operation in 2006, but will decrease steadily thereafter through 2013.[23] As a result, NEMA's electric system relies heavily upon the Mystic power station for current and future electric system reliability.

Natural Gas System Utilization

As previously mentioned, 80% of the natural gas used annually in New England is delivered by interstate pipelines. However, according to the Federal Energy Regulatory Commission (FERC), New England's interstate pipelines are fully loaded, exceeding 90% capacity, during the three winter months. Figure 2-4 below demonstrates that during peak winter months, the region's interstate pipelines have little excess capacity.[24] LNG from the Distrigas facility and LDCs' satellite facilities supplement pipeline delivered supplies. On the other hand, during the summer months, when natural gas is needed for meeting peak electricity needs, there is plenty of excess capacity to serve demand.

[23] ISO-NE, "Regional Transmission and Expansion Plan 2004 (RTEP 2004), October 2004.
[24] FERC, "New England Gas Infrastructure Report," Dec. 2003.

Figure 2-4
New England Interstate Pipeline Utilization



Source: FERC, EEA

In addition to the pronounced seasonal swings in capacity utilizations, the major pipelines serving New England experience large, daily fluctuations in flows. Appendix B includes graphs reporting the daily throughput of the Algonquin and Tennessee pipelines (the latter owned by El Paso) serving New England for the period November 2002 through November 2004. These throughput variations (some actually exceed the pipeline's design capacity) are largely accommodated by modulations in the compression of gas within the lines.

The following table shows the daily gas import capacities of interstate pipelines and the sustainable daily throughput capacity of the Distrigas facility.[25]

Table 2-2
Delivery Capacity of Pipeline System and Distrigas

Pipeline	2004 (Bcf/d)
Algonquin	1.435
Tennessee	1.090
Maritimes and Northeast	.440
Portland	.210
Iroquois	.285
Vermont Gas	.050
Distrigas	.715
Total	**4.225**

Source: FERC, Distrigas

[25] FERC, "New England Gas Infrastructure Report," Dec. 2003; FERC, "Technical Appendices Report for New England Gas Infrastructure Report," and Distrigas website.

Conclusion

New England has a unique natural gas delivery system composed of 5 major interstate pipelines, several intrastate pipelines and one of only four LNG facilities in this country.[26] Currently, the region's natural gas demand is met mostly with natural gas transported as vapor from remote supply regions in the U.S. Gulf Coast and Canada. Over the years, the gas industry has integrated LNG into the region's natural gas supply mix in order to supplement interstate gas supplies and to have the in-region reserves to meet winter peak requirements. New England has no underground natural gas storage facilities to maintain a local reserve supply for peak demand periods. This is due to the region's lack of geological requirements for underground natural gas storage. (New England's interstate pipelines do carry some natural gas supply from underground storage facilities in New York and Pennsylvania.) Today, the Distrigas LNG facility and the LDCs' satellite LNG facilities are critical to meeting the region's peak winter natural gas demand.

[26] The other three are: Cove Point, MD; Elba Island, GA; and Lake Charles, LA.

Chapter 3: New England Natural Gas Demand Outlook

Understanding the extent of natural gas demand growth is the first step in evaluating appropriate options to serve New England's future natural gas needs. A comparison of publicly available forecasts from four organizations[27] shows that energy experts have differing views on New England's natural gas demand growth. (Dissimilar underlying assumptions are the main reason for the variations among forecasts and these suppositions are discussed throughout the chapter.) After assessing these four forecasts, we can bound the likely range of growth rates in winter peak gas demand between two cases: normal demand and high demand. These are mainly a function of two drivers: weather, which determines the demand for gas for space heating, and electricity demand, which determines the use of gas for power generation. The normal case represents average weather and electricity demand conditions, and the high case represents extreme weather and electricity demand conditions. Next, the forecast demand is measured against the region's existing natural gas supply capabilities. This comparison shows if and when the region will experience any supply/demand shortfalls. We begin by describing each of the four demand forecasts and the way they differ.

NATURAL GAS DEMAND FORECAST

Natural Gas Demand from the Residential, Commercial, and Industrial Sectors

1. U.S. Department of Energy Forecast

The U.S. Department of Energy's (DOE) Energy Information Administration's (EIA) Annual Energy Outlook 2004 (AEO 2004) includes a comprehensive, New England specific forecast of natural gas demand by sector through 2024.[28] The AEO is customarily used as the "reference" forecast for comparison purposes by other forecasters. In addition, forecasters traditionally have used many of the assumptions used for the AEO when more reliable or more detailed assumptions are not available. Table 3-1 shows the AEO 2004 forecast of New England natural gas consumption and average annual growth rate (AAGR) by sector for selected years out to 2024.

According to EIA's data, total natural gas consumption in New England is expected to grow at an annual average rate of 1.38% between 2004 and 2024 from 882.3 trillion Btu in 2004[29] to 1,161.3 trillion Btu by 2024, an overall increase of 31.6%. It is interesting to note that natural gas consumption is expected to grow in all sectors, albeit at different rates.

A review of all the sectors shows that the residential sector has the smallest average annual growth rates at 0.79% from 2004-2012 and 0.70% from 2004-2024. Commercial use is also expected to grow

[27] The U.S. Department of Energy's Energy Information Administration (EIA); ICF Consulting for the Regional Greenhouse Gas Initiative (RGGI); ISO New England, Inc.; and Energy and Environmental Analysis, Inc. (EEA).

[28] The AEO 2004 forecast is produced using the National Energy Modeling System (NEMS), which is composed of a set of integrated and interdependent models that cover all fuels and all demand sectors.

[29] It is important to note that the 2004 values in Tables 3-1, 3-2, and 3-3 are not actual. Rather, they are results produced by forecasting models. We have used 2004 as a base year in order to calculate average annual growth rates, which are the key metrics for our forecast comparisons.

at an annual rate slightly higher (1.73%) in the early years (2004-2012) and smooth out to 1.27% through 2004 to 2024.

Underlying factors related to residential and commercial demand growth include housing development, fuel switching from other forms of heating, and population growth. The cause for growth in these sectors is influenced by the price of natural gas and alternative fuels. Other factors that drive natural gas consumption in the residential and commercial sectors include the amount of energy efficiency and conservation implemented.

The EIA forecasts that New England's industrial sector will have the second highest rate of natural gas annual growth. One reason is that the AEO assumes that within the industrial sector, output will grow (on a national and regional level) and that this sector will use more natural gas for combined heat and power (CHP) applications and for boiler use.[30]

The electric generation sector shows an annual growth rate of 0.67% in the years between 2004 and 2012. During the time frame 2004 to 2024, however, the annual growth rate for natural gas in this sector more than doubles (1.48%). (Later on, this chapter provides a more detailed analysis of the power generation sector's natural gas needs.)

The amount of natural gas consumed in the transportation sector is the smallest of all the sectors, but on the basis of annual growth rates, this sector has the highest growth rate.

Table 3-1
Natural Gas Demands by Sector, New England
(Trillion Btu)[31]

	2004	2005	2006	2009	2012	2015	2018	2021	2024	*AAGR* 2004-2012	*AAGR* 2004-2024
Residential	196.6	197.4	200.0	205.0	209.3	210.7	214.9	220.4	226.2	0.79%	0.70%
Commercial	144.8	148.4	152.6	160.6	166.1	169.0	173.9	180.3	186.3	1.73%	1.27%
Industrial	151.5	156.8	160.8	170.3	177.7	185.5	197.9	209.6	224.0	2.02%	1.97%
Generation	378.9	337.0	368.0	382.2	399.7	367.0	416.9	476.4	508.1	0.67%	1.48%
Transportation	10.5	10.8	10.3	12.0	13.6	14.4	14.5	15.6	16.6	3.33%	2.33%
Total	882.3	850.3	891.7	930.1	966.4	946.6	1,018.1	1,102.4	1,161.3	1.14%	1.38%

Source: EIA, MA DOER

2. *New England Local Natural Gas Distribution Companies' Forecast*

Table 3-2 compares the EIA's residential, commercial and industrial natural gas demand figures from Table 3-1 to consumption estimates provided by the New England local natural gas distribution companies (LDCs), through 2012. The LDC data are in terms of "Normal" and "High" rates of growth. (EIA figures are for normal growth rates.)

[30] U.S. DOE/EIA, "AEO 2004," p.45.
[31] A trillion Btu is approximately 1 Bcf.

Both forecasts anticipate overall natural gas growth and sector growth. In comparison to EIA's forecast, the LDCs' forecast also shows that the residential sector's gas consumption will grow during the period between 2004 and 2012. The LDCs project a Normal annual rate of growth of 1.40%. This percentage is almost double the rate of growth for this sector as forecasted by EIA (0.79%) for the same period. In the High case for residential, the LDCs forecast a 1.74% annual rate of growth.

The LDCs' commercial/industrial natural gas consumption is forecasted to grow at annual rates through 2012 of 2.43% and 3.01%, respectively for the Normal and High cases. These percentages, however, are 29% higher in the Normal case and 60% higher in the High case than EIA's projections in this sector.

Table 3-2
Natural Gas Demand Forecast from Non-Generation Sectors, Forecast Comparison
(Trillion Btu)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	AAGR 2004-2012
				Residential						
LDC (Normal)	196.6	200.1	201.5	205.0	207.9	210.7	213.6	216.6	219.7	1.40%
LDC (High)	210.8	214.2	217.5	222.1	226.0	229.7	233.7	237.8	242.0	1.74%
EIA	196.6	197.4	200.0	201.8	203.9	205.0	206.7	207.9	209.3	0.79%
				Commercial & Industrial[32]						
LDC (Normal)	164.6	169.5	173.0	177.7	181.8	185.5	190.1	194.7	199.6	2.43%
LDC (High)	180.0	185.4	191.3	197.7	203.3	208.5	214.9	221.5	228.3	3.01%
EIA	296.3	305.2	313.4	319.5	324.5	330.9	336.2	340.3	343.8	1.88%
				Interruptible						
LDC (Normal)	32.7	32.6	32.6	34.6	34.6	34.8	35.0	35.2	35.5	1.02%
LDC (High)	30.2	30.1	30.3	32.2	32.3	32.6	32.8	33.1	33.5	1.29%
				Competitive Supplies						
LDC (Normal)	99.0	101.9	110.8	112.1	113.1	114.4	118.1	122.0	126.1	3.08%
LDC (High)	111.9	113.7	123.6	123.9	124.2	124.9	128.2	131.8	135.6	2.44%
				Total						
LDC (Normal)	492.9	504.1	517.9	529.4	537.4	545.3	556.8	568.6	580.9	2.02%
LDC (High)	532.9	543.7	562.7	576.0	585.9	595.7	609.6	624.2	639.4	2.21%
EIA	492.9	502.5	513.4	521.3	528.5	535.9	542.8	548.1	553.1	1.45%

Sources: New England LDCs, EIA, MA DOER

Demand from the Electric Generation Sector

A number of energy experts have put forth forecasts of New England's natural gas needs for electric generation. This report compares forecasts from the AEO 2004, RGGI, ISO-NE, and EEA, Inc. (Table 3-3).[33]

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[32] The EIA does not split C&I usage into interruptible and competitive supplies.

[33] AEO 2004 was defined in the text. RGGI refers to the reference forecast produced by ICF Consulting in support of the Regional Greenhouse Gas Initiative, 2004 value imputed by MA DOER. The ISO-NE forecast was derived using 8000 btu/kWh from the generation forecast produced for "Natural Gas and Fuel Diversity Concerns in New England and the

In 2006, both EIA and RGGI are similar with only a slight difference in the amount of natural gas used for electric generation (367 vs 368 tBtu). In that year, the ISO-NE forecast shows a larger amount of gas consumed at 483.9 tBtu. This is a difference of 32% from the EIA and RGGI forecasts.

In later years, the discrepancies among the forecasts grow much larger. For example, by 2012 at one end of the spectrum the AEO 2004 forecast predicts gas consumption will be 399.7, while ISO-NE estimates it at 567 tBtu. The difference is a magnitude of 167 tBtu or 42%.

Table 3-3
Natural Gas Demand From New England's Generator Sector, Forecast Comparison
(Trillion btu)

	2004	2005	2006	2009	2012	2015	2018	2021	2024	AAGR 2004-2012	AAGR 2004-2024
AEO 2004	378.9	337.0	368.0	382.2	399.7	367.0	416.9	476.4	508.1	0.67%	1.48%
RGGI	357.1	n/a	367.0	384.0	423.0	458.0	484.0	470.0	470.0	2.14%	1.38%
ISO-NE	382.6	452.0	483.9	521.8	567.0	n/a	n/a	n/a	n/a	5.04%	n/a
EEA	352.2	389.3	386.8	456.1	509.7	583.6	601.2	n/a	n/a	4.73%	n/a

Sources: EIA, RGGI, ISO-NE, EEA, MA DOER

Comparison of Underlying Assumptions in the Forecasts

The different forecasts in Table 3-3 show wide spread differences in average annual growth rates. Therefore, it is important to explain and to understand the reasons for such discrepancies. Appendix C shows pertinent, underlying assumptions to the forecasts found in Table 3-3. These assumptions are used to make clear and compare the disparities in the four forecasts. It is, however, important to note that each forecast features a different set of modeling methods in addition to the assumptions. At best, the explanation provided herein should only be considered an informed analysis of the assumptions and a reasonable attempt at describing the logic behind the forecasts, not a detailed comparison of the specific methods and models used.

1. AEO 2004

The AEO 2004 forecast indicates the lowest growth rate in gas demand from electric generation during the early years (2004-2012), though the growth rate does increase in later years. AEO assumes the lowest increase in natural gas capacity additions in that early period. Underlying this conclusion is the AEO assumption (or modeling result) that oil-fired generation in New England will continue to remain a viable option to gas-fired generation. Reinforcing this assumption are the lower oil prices paid by generators compared to those found in the other forecasts. The other three forecasts all implicitly feature a continually decreasing dispatch for oil-fired generators, due to assumptions about their relative environmental and economic disadvantages.

Boston Metropolitan Electric Load Pocket", Levitan & Associates, Inc. July 1, 2003 based on RTEP03 planning process. The EEA values are from Energy and Environmental Analysis, Inc. October 2004 Base Case.

2. *ISO-NE*

The ISO-NE forecast represents the other extreme for forecasts of natural gas demand by generators. Like the EIA, the ISO-NE forecast assumed a low gas-price outlook.[34] Moreover, they forecast large additions to gas-fired generation capacity while including no renewable capacity additions. Clearly, the ISO-NE forecast assumes gas to be the almost exclusive fuel-of-choice for fulfilling future load growth.

3. *Energy and Environmental Analysis, Inc.*

The forecast growth rate of EEA is quite similar to the ISO-NE forecast, but gas-fired generation accounts for a smaller percentage of total generation than found in the ISO-NE forecast. This difference may be partly explained by the renewable capacity additions that are assumed in the EEA figures. The price of gas is not a deterrent to the dispatch of gas plants, given that EEA assumes the highest natural gas outlook of the forecast group. At the same time, EEA assumes a correspondingly high outlook for oil prices.

4. *RGGI*

The RGGI forecast growth rate falls between the low of the EIA and the two other forecasts that are on the high side. The RGGI forecast assumes relatively high price paths for natural gas and oil and a concurrent loss of oil-fired generation. Most importantly, the RGGI forecast contains a very positive outlook for renewable development, which would displace some gas-fired generation. Possibly, high natural gas prices would elevate the potential revenues that renewable generators would receive, thus increasing their competitiveness with gas-fired generation.

Forecast Insights

As a group, the forecasts provide a number of insights regarding the future. Natural gas will continue to be the critical fuel for electric generation, but New England's dependence on natural gas may be mitigated depending on particular assumptions concerning generation choices. A critical assumption is the amount of oil-fired generation available in the future to displace the gas used in gas-fired generation. As shown in Appendix C, the assumed heat rates[35] for natural gas capacity additions are much better than heat rates that can be attained by existing oil-fired combustion turbines or combined cycle (fossil steam) plants. Assumptions concerning the price of oil will also be key, but these prices tend to be correlated with natural gas prices, so this variable may not be as critical. Another key assumption is the rate of renewable generation expansion. Greater renewable construction should displace at least some incremental gas-powered generation. Finally, we have relied on relatively conservative assumptions regarding adoption of newer technologies such as integrated gasification combined cycle (IGCC) plants. The forecasts described above assume relatively stable technology

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[34] It should be noted that the ISO-NE forecast is taken from an older document (July 2003) that may have preceded more recent increases in natural gas prices. Unfortunately, there was no alternative publicly available forecast or publicly released results that could be used.

[35] The amount of fuel energy required by a power plant to produce one kilowatt-hour of electrical output. A measure of generating station thermal efficiency, generally expresses in Btu per net kWh. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kWh generation.

choices in their costing and dispatch models. Appendix D discusses the pros and cons of including a wider range of technologies (beyond natural gas and renewables) to serve electricity demands.

Peak Day Demand Forecast

The most critical measure in determining regional natural gas capacity adequacy is the regional peak day supply-demand balance. The first step in evaluating the peak day balance was to create a peak day gas demand forecast over the long term. This required a deterministic assessment of the peak day demand forecasts of the two major customers of the New England interstate pipelines: LDCs and the bulk electric power (generation) sector. The peak day interstate pipeline demand evaluation looked at the LDCs' natural gas demands for space heating uses and the ISO-NE's natural gas demands for power generation.

1. LDC Delivered Demand Calculation

Table 3-4 illustrates the "normal" and "high" forecasts for 2005-2012 of peak day natural gas demand delivered by New England LDCs. To first calculate this, the 2004 design peak day demand of 3.725 Bcf/day was used as the base quantity for the "high" peak day demand forecast. (The actual 2004 peak sendout of 3.83[36]. Bcf/day occurred on January 15th. For this study, the LDCs' design day forecast figures represent a more reasonable assumption than last year's extreme peak sendout.) An average 2004 normal to high peak day demand differential of 13% was first calculated using individual LDC forecast data. This discount was then applied to the design peak day demand to derive the "normal" 2004 peak day demand of 3.24 Bcf/day.

The normal and high forecasts' base demand figures were increased per weighted Average Annual Growth Rates (AAGRs) derived from available LDC forecasts of peak day for their entire demand (LDCs do not forecast peak day by customer type). The normal AAGR was 2.12%, while the high forecast rate was 2.38%. Note that the LDCs' peak day forecasts are slightly higher than their throughput forecasts, found in Table 3-2. Keyspan, the largest investor owned LDC in New England serving Eastern Massachusetts, forecast the highest AAGR of 3.81%. Keyspan serves approximately 35% of New England's peak day demand gas.

2. Natural Gas Energy Efficiency in New England

In recent years, some LDCs in New England have started to implement natural gas energy efficiency programs that focus on reducing consumers' gas usage for space heating and gas-operated appliances. The seven LDCs in Massachusetts collect $25 million annually from Massachusetts ratepayers to finance these investments. These companies deliver market transformation[37] programs that focus on energy efficient gas equipment as well as deliver unique efficiency programs and services for their service territories. The companies' expenditure for programs they operate jointly (known as

[36] Northeast Gas Association, "2004 Statistical Guide," Sept. 2004.

[37] Market transformation programs attempt to influence behavior of parties upstream from customers by encouraging manufacturers and retailers to develop and sell equipment and by training installers and service technicians. The legislative and regulatory goal of these programs is to establish higher efficiency requirements in building codes and in equipment standards.

GasNetworks)[38] averages between 35% and 40% of the total $25 million. An example of one joint program is a substantial rebate for residential consumers who install high-efficiency gas space heating equipment.[39] Recently, Massachusetts regulators, in addition to looking at the cost-effectiveness of these programs, began to track annual and lifetime savings from these programs. Using the limited data currently available, we estimate these programs result in displacement of natural gas at a cost of $2.69 million per Bcf. This estimate is based on planned savings and cost figures over the 2004-2008 period in recently filed Massachusetts LDCs' plans. In other New England states, some LDCs that are subsidiaries of Massachusetts LDCs, have adopted some of the market transformation programs of GasNetworks. Others have implemented more limited gas efficiency programs of their own.

Expanded investments in gas energy efficiency programs may yield even greater reliability enhancements and even lower overall costs than most other options. To confirm this expectation, however, considerably more information on the costs and performance of these programs would be needed. Hence, we did not explicitly include the impact of these programs in the demand forecasts below.

3. *Electric Generation Demand Calculation*

The electric power sector's peak day gas demand is a difficult quantity to pinpoint precisely due to the commercial sensitivity of power market data. ISO-NE administers New England's wholesale marketplace and is required to mask identities of individual generator market data, but does provide aggregated market data which was used in this study to calculate gas power demands for generation.

To derive the electric generators' peak day gas demand, an initial assumption was that all gas-fired capable power plants, net certain adjustments explained below, need to operate and be dispatched on the theoretical peak day to maintain electric reliability. This can be considered a supply-side gas demand perspective.[40]

The total natural gas capable installed capacity for winter 2003-04 was 17,341 MW or 52% of all installed generating capacity in New England.[41] This amount was discounted for two factors: the average winter daily capacity outage (forced and unforced) of 5,110 MW and unit capacity factors of 75% and 25% for Combined Cycles (CCs) and Combustion Turbines (CTs) respectively. (Only two generating technology groups were assumed for this study, combined cycle and combustion turbine.) The net result of these two adjustments was 7,523 MW of operable capacity for the peak day last winter season.

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[38] GasNetworks is a collaborative consisting of local natural gas companies serving residential and commercial & industrial customers throughout New England. It has been promoting energy efficiency and the use of high efficiency natural gas technologies since 1997.

[39] According to GasNetworks, "Space heating equipment is typically the largest energy user in the home. If a natural gas furnace or boiler is more than 20 years old, it is probably running very inefficiently compared to today's models. One way to help offset the rising cost of energy and significantly reduce heating costs is to replace an old furnace or boiler with new high-efficiency heating equipment. In fact, a new furnace or boiler can save up to 30% of your heating energy use."

[40] This method considers natural gas demand from a supply-side perspective. Another approach, though not used, is to calculate the peak day gas demand considering actual gas-fired unit commitments from recent peak electric days experienced in New England. This is a demand-side perspective.

[41] ISO-NE, "2004 CELT Report", April 2004. Of the 17,341 MW, only 7,309 MW are single fuel capable, while the remaining 10,032 MW are dual fuel (gas and oil) stations.

Then, the adjusted installed capacity figures (CT and CCs) were multiplied by assumed heat rates (MMBtu/MWh) according to their technology class and by 24 (hours/day) to arrive at peak day gas demands. Of the adjusted 7,523 MW installed capacity for winter 2003-04, 6,698 MW were CC technology while the remaining 825 MW were considered CTs. The CC group was assigned a heat rate of 8.5 MMBtu/MWh, while the conventional CT group were assigned a 10.7 MMBtu/MWh.[42] Using this calculation, the potential electric generation gas demand for winter 2003-04 was 1.53 Bcf/day. However, because we assume only 61%[43] of the gas capable power generators possess firm gas contracts, the 1.53 Bcf/day peak day demand for 2003-04 was adjusted down accordingly to 0.93 Bcf/day. [44]

For this report, the peak day demand of 0.93 Bcf/day was used as the base number to calculate the "normal" and "high" peak day gas demand for 2005-2012. The growth rate of 3.15% is used for the "normal" forecast and 5.04% is used for the "high" peak day forecast. The 3.15% rate is an average of the forecast growth rates from Table 3-3, while 5.04% is the growth rate forecast by the ISO-NE.

It should be noted that in November 2004, ISO-NE implemented Operating Procedure #20 which provides formal processes that address, under certain circumstances, ISO-NE scheduling during Cold Weather conditions, allowing natural gas units to receive their commitment status in sufficient time to purchase gas by the gas nomination deadline. It also provides ISO-NE with additional authority in outage scheduling to avoid electric reliability problems.

4. *Peak Day Forecast Results*

The total New England peak day forecast is the sum of the LDC delivered demand plus the electric generation peak day demand on the interstate pipelines. The "normal" peak day forecast result for 2012 is 5.06 Bcf/day, while the "high" peak day forecast for 2012 is 5.87 Bcf/day as shown in Table 3-4 and Figure 3-1. The average annual growth rate for the "normal" peak forecast is 2.35%, while the AAGR for the "high" forecast is 2.95%.

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[42] ISO-NE, "Final Report on Electricity Supply Conditions in New England During the January 14-16, 2004 Cold Snap," Oct. 2004, p. 51. Figure 9 illustrates the implied heat rates from winter 2003-04. A reasonable average implied heat rate realized by the power pool is 8.5 MMBtu/MWh under winter conditions. State-of-the-art units operate at a higher efficiency, but not all units are state-of-the-art, so it is assumed that several units operate at less than full load and consequently less efficiency.

[43] The source of this figure is FERC, "New England Gas Infrastructure Report," Dec. 2003. Unlike the FERC study, we further assume that either (a) these plants are able to secure transportation for that amount or (b) some non-firm pipeline customers will be served.

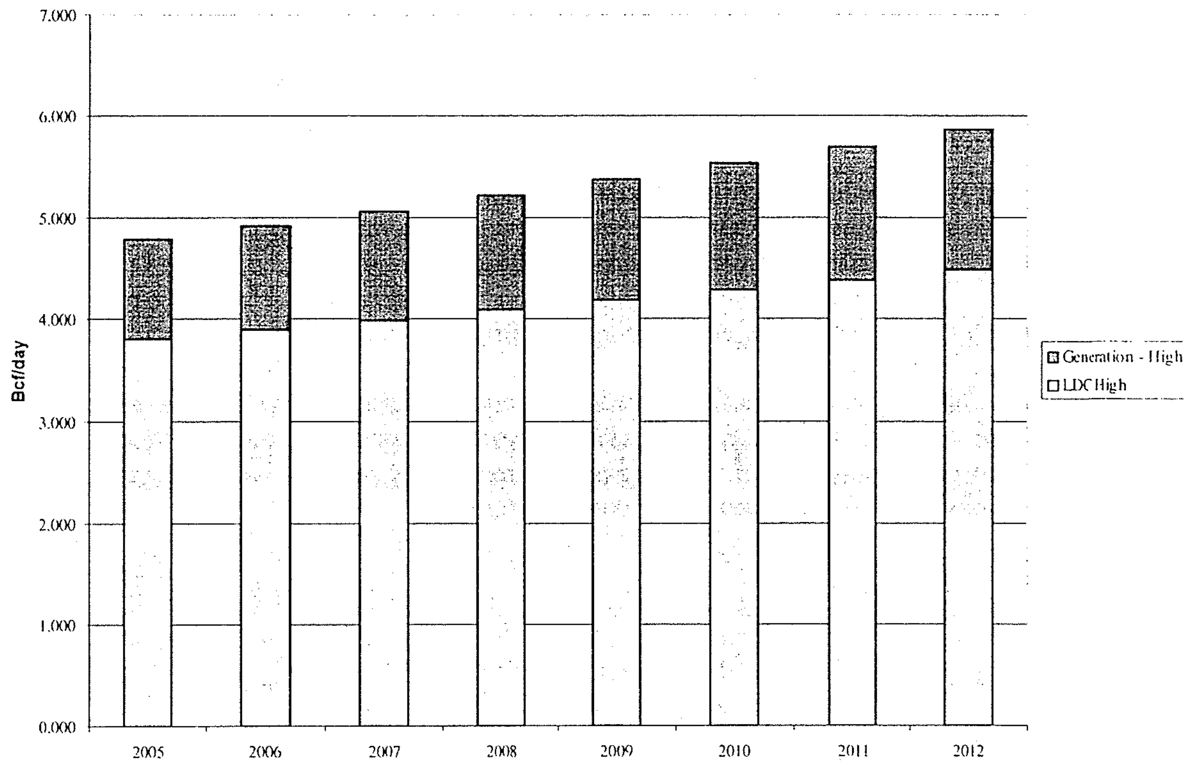
[44] ISO-NE, "Final Report on Electricity Supply Conditions in New England During the January 14-16, 2004 Cold Snap," Oct. 2004, p. 44. "On January 14, 2004, during the OP4 conditions of Hour Ending 6:00 p.m., the New England control area experienced 8,927 MW of unavailable capacity." "...gas-capable units account for the largest category of outages, with 81 percent of the total unavailable capacity." This outage event illustrates how gas-fired generators impact gas demands during extreme conditions: they sell their gas supplies to LDCs, thus lessening gas demand from the power sector, and avoid significant market and operating risks at the same time. According to a study, "Post Operational Assessment of New England's Interstate Pipeline Delivery Capability During the January 2004 Cold Snap," done in March 2004 by Levitan and Associates for ISO-NE (p.8), "...pipeline deliveries to power plants were only in the range of approximately 0.3 to 0.5 Bcf, *far less* than the Peak Day projection of over 1.0 Bcf."

Table 3-4
Peak Day Natural Gas Demand Forecasts
2005-2012
Bcf/day

	2005	2006	2007	2008	2009	2010	2011	2012	AAGR 2004-2012
				LDC-Delivered Demand					
Normal	3.343	3.414	3.487	3.560	3.636	3.713	3.792	3.872	2.12%
High	3.814	3.904	3.997	4.092	4.190	4.290	4.392	4.496	2.38%
				Generation Demand					
Normal	0.96	0.99	1.02	1.05	1.09	1.12	1.16	1.19	3.15%
High	0.98	1.03	1.08	1.13	1.19	1.25	1.31	1.38	5.04%
				Total Demand					
Normal	4.30	4.40	4.51	4.61	4.72	4.83	4.95	5.06	2.35%
High	4.79	4.93	5.08	5.22	5.38	5.54	5.70	5.87	2.95%

Sources: Table 3-2, Table 3-3, NGA, MA DOER

Figure 3-1
Peak Day Gas Demand –
High Demand Forecast 2005-2012
Combined LDC & Natural Gas-Fired Power Generation
(Bcf/day)



NATURAL GAS SUPPLY CAPACITY FORECAST

Peak Day Supply Delivery Capacity Forecast

Determining the peak day supply delivery capacity forecast over the long term is the next step in evaluating the peak day gas balance. The gas supply capacity components considered first include existing, infrastructure such as the region's interstate pipelines, LNG import terminals and LDC vaporization capability. Next, expansion plans such as New England pipeline capacity expansion projects, new regional LNG terminals and vaporization projects are considered.

1. Existing Interstate Natural Gas Pipelines Serving New England

The first component examined was existing delivery capacity of the major interstate pipelines which serve New England. For the time period examined, 2004-2012, Table 3-5 shows that 6 interstate pipelines have a forecast capacity of 3.51 Bcf/day available to help meet the New England's peak day natural gas demand. Supplies delivered by Algonquin and Tennessee, the largest regional supply pipelines, originate in the U.S. Gulf Coast, while Iroquois, PNGTS, and Maritimes and Northeast supply gas that comes from western Canadian and eastern Canadian, respectively.

2. Distrigas LNG Terminal

The Distrigas LNG terminal in Everett, MA is taken into account next. The peak day capacity of the Distrigas terminal is assumed to be approximately 0.715 Bcf/day, which is the current sustainable daily capacity.

3. New England LNG Storage and Vaporization Tanks

The third capacity component of New England's gas supply portfolio is the LNG storage and vaporization tanks located in 5 New England states. The current vaporization capacity accounts for 1.22 Bcf/day and is expected to be available through 2012.

4. Infrastructure Expansion Projects within New England

The base case in Table 3-5 includes a few projects that are expected to come on line before 2012 and increase peak day capacity. The projects include two pipeline expansions and one storage vaporization facility in Connecticut.[45] These projects are the only projects where construction appears firm due to their financing and/or regulatory progress.

[45] The Everett Lateral project developed by Duke Energy/Algonquin Gas Transmission made minor pipeline system modifications to accommodate the transport of about 60 million cubic feet/day of additional gas volumes originating from Distrigas was completed in 2004 but is not included in the existing Algonquin pipeline capacity. The Northeast ConneXion Project by El Paso Corp./Tennessee Gas Pipeline is designed to deliver 100,000 dekatherms of natural gas per day on Tennessee's system to New England. Yankee Gas Services Company has regulatory approval from the CT Department of Public Utility Control to construct a 1.2 Bcf LNG storage facility with 60,000 Mcf/day of vaporization capacity.

Table 3-5
Peak Day Capacity Analysis
2004-2012
(Bcf/Day)

	2004	2005	2006	2007	2008	2009	2010	2011	2012
Existing Pipeline[46]									
Algonquin	1.435	1.435	1.435	1.435	1.435	1.435	1.435	1.435	1.435
Tennessee	1.090	1.090	1.090	1.090	1.090	1.090	1.090	1.090	1.090
Iroquois	0.285	0.285	0.285	0.285	0.285	0.285	0.285	0.285	0.285
Vermont Gas	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
Portland	0.210	0.210	0.210	0.210	0.210	0.210	0.210	0.210	0.210
Maritimes	0.440	0.440	0.440	0.440	0.440	0.440	0.440	0.440	0.440
Total Existing Pipeline	3.510	3.510	3.510	3.510	3.510	3.510	3.510	3.510	3.510
Distrigas[47]	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715	0.715
Vaporization[48]	1.22	1.22	1.22	1.22	1.28	1.28	1.28	1.28	1.28
Pipeline Expansion Projects[49]	-	0.06	0.06	0.06	0.16	0.16	0.16	0.16	0.16
Total Peak Day Capacity	5.44	5.51	5.51	5.51	5.67	5.67	5.67	5.67	5.67

Sources: FERC, Distrigas website, NEGA, CT Dept of Public Utility Control

These data are depicted in Figure 3-2.

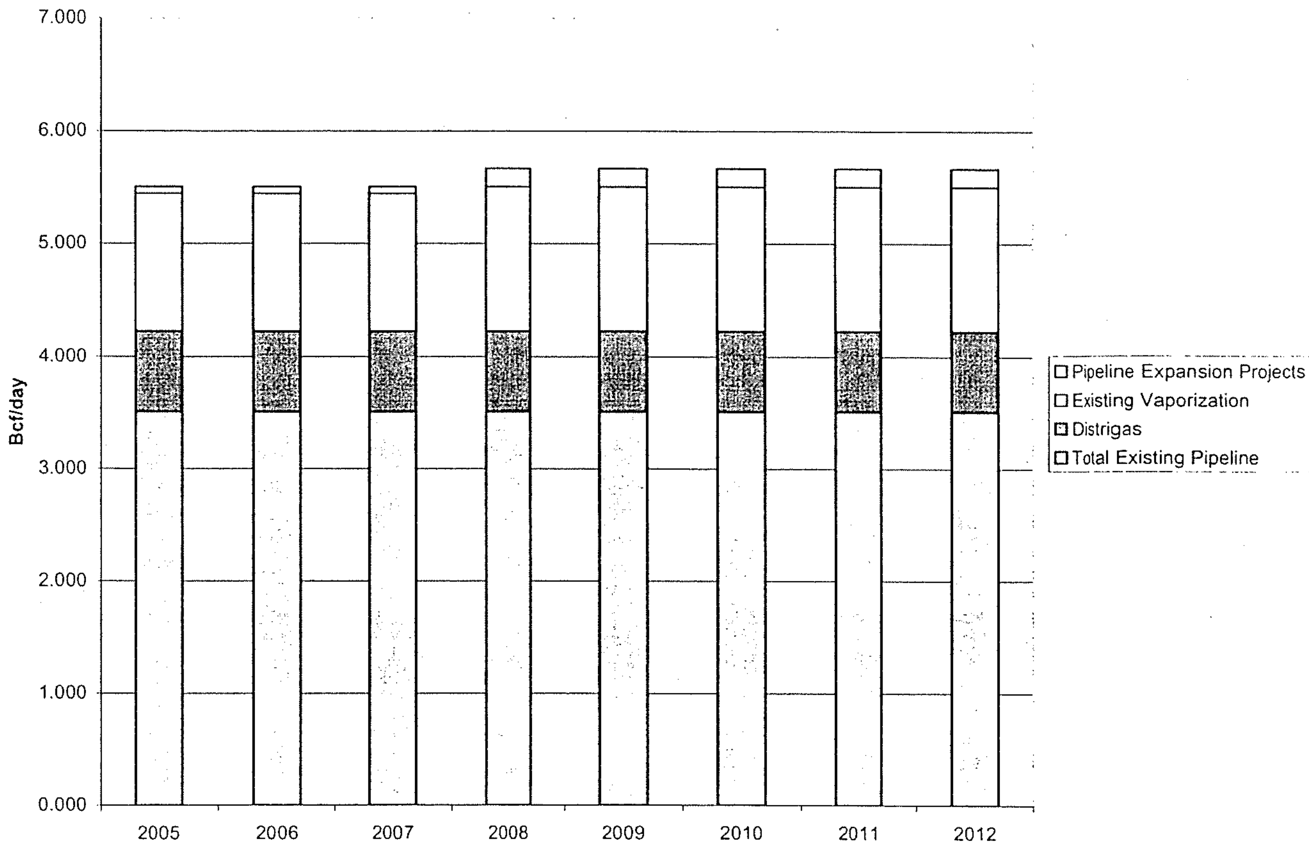
46 FERC, "New England Gas Infrastructure Report," Dec. 2003; FERC, "Technical Appendices Report for New England Gas Infrastructure Report."

47 Distrigas website. "The Terminal's installed vaporization capacity (nameplate) is approximately one billion cubic feet per day, with a sustainable daily throughput capacity of approximately 715 million cubic feet per day."

48 Northeast Gas Association, "Gas Supply Information for The New England Gas Industry," Dec. 2004;
CT Department of Public Utility Control, Docket # 01-05-19RE07, "Application of Yankee Gas Services Company for a Rate Increase, Phase1 – LNG Facility Costs," Sept. 2004.

49 Northeast Gas Association, "Planned Enhancements, Northeast Pipeline & Storage Systems," Jan. 2005.

Figure 3-2
Peak Day Capacity Analysis
2005-2012
Bcf/day



ANALYSIS OF DEMAND AND SUPPLY BALANCE

Potential Supply Capacity Shortfall in New England

Table 3-6 summarizes the annual forecast peak day demand vs supply balance (Bcf/d), termed in this report as "reserve margin." It is a calculation of the total peak day capacity (see Table 3-5) minus the total peak day demands, "normal" vs "high" (see Table 3-4). It should be noted that each reserve margin column in Table 3-6 also accounts for existing electric energy efficiency programs which are assumed to continue through 2012 and renewable energy supplies. The energy efficiency programs are forecast to provide an avoided peak day gas demand in 2012 of 0.11 Bcf/day. Renewable electricity supplies are also forecast through 2009[50], and an avoided peak day gas demand has been calculated in accordance. The renewable energy supply is forecast to provide peak day gas demand

[50] Attainment of renewable portfolio standards is assumed at a level of 4% (of total Massachusetts electricity consumption served by new renewables) in Massachusetts by 2009 and remaining at that level.

relief of 0.06 Bcf/day in 2012. These figures are modest, but they do play an important role during extreme weather conditions and strained capacity events.

Table 3-6 shows the surplus/shortfall for forecast scenarios when 1) vaporization of LNG satellite terminals is included in the available supply capacity and 2) the vaporization capability has been exhausted (drawn to zero), due to contingencies such as extreme weather conditions.[51] The analysis, except for the "after vaporization" scenarios, *assumes that New England's interstate pipeline and LNG delivery infrastructure is working at full capacity and that natural gas supplies are available to flow through the system.*

The data show that if demand remains at "normal" growth rates and LNG storage gas is available, then the region should see a margin through 2012. Even if the demand growth rate is "high", with LNG storage gas available there remains a reserve margin, although very small, until the year 2012 when there is a deficit.

The table shows that a shortfall is forecast to occur by 2006 under the "normal" demand scenario and as early as 2005 under the "high" demand scenario after vaporization has been exhausted (in a contingency such as an extended cold snap).

The consequences of a shortfall in pipeline capacity or supplies also can be dire. A pipeline reserve margin shortfall and subsequent pressure drop in the LDCs' distribution pipelines can set off an extended gas outage that would risk public safety in freezing temperatures conditions.

Table 3-6
Reserve Margins Assuming Existing Volumes of Natural Gas
2005-2012
(Bcf/day)

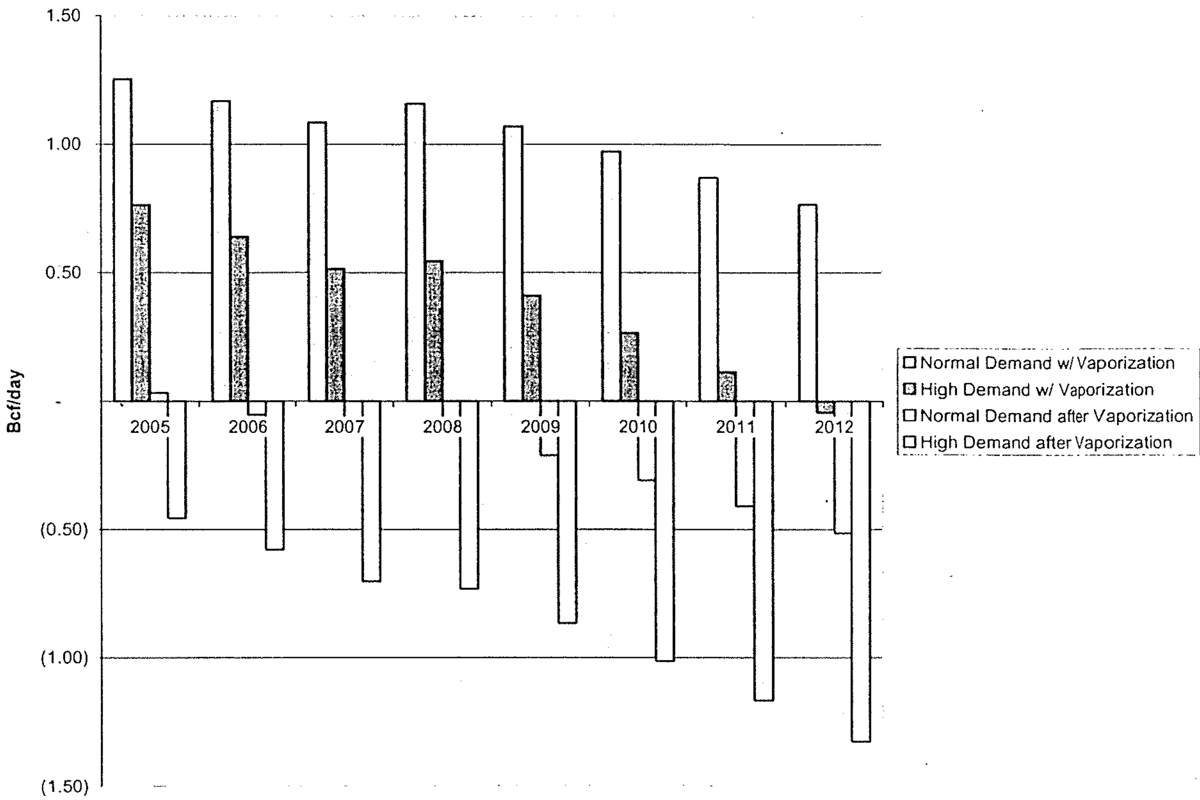
	2005	2006	2007	2008	2009	2010	2011	2012
	With Vaporization							
Normal Demand	1.25	1.17	1.08	1.16	1.07	0.97	0.87	0.77
High Demand	0.76	0.64	0.52	0.55	0.41	0.27	0.11	(0.04)
	After Vaporization							
Normal Demand	0.03	(0.05)	(0.14)	(0.12)	(0.21)	(0.31)	(0.41)	(0.51)
High Demand	(0.46)	(0.58)	(0.70)	(0.73)	(0.87)	(1.01)	(1.17)	(1.32)

Source: Tables 3-4 and 3-5; MA DOER

[51] The extreme-demand scenario assumes all vaporization capacity from satellite LNG storage is exhausted. However, it is quite unlikely that the LDCs would allow such conditions to ever occur. Instead, LDCs are constantly monitoring their current and forecast gas supplies and LNG vaporization capacities. If levels of stored LNG fall below specified levels, LDCs will likely try to get more gas supplies from Distrigas and other natural gas supply sources, such as spot pipeline gas during non-peak days, to replace used LNG quantities. Unfortunately, an estimate of a minimum LNG vaporization level was unattainable from publicly available data. Thus, this report does not include this as a separate scenario nor does it adjust the "after-vaporization" estimates. Nevertheless, it is important to realize that it may be more realistic to assume a "limited" vaporization rather than a "no or after" vaporization event. For example, an assumption could be that half of the vaporization capacity (0.6 Bcf/day) would be the lowest allowable level, thereby improving the reserve margins in the "after vaporization" scenarios in Table 3-6.

Figure 3-3 shows in a graph the data in Table 3-6.

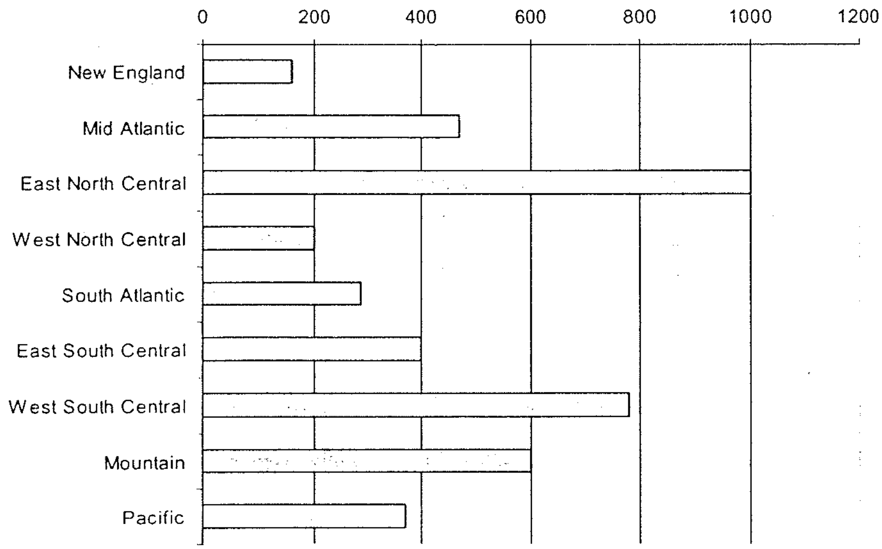
Figure 3-3
Supply Capacity Reserve Margin Forecast
Before and After Vaporization Capacity
2005-2012
Bcf/day



Other Factors that May Impact New England Natural Gas Supplies

It is important to also look at factors that might impact New England's natural gas supplies. These include forecasts of natural gas demand in other parts of the country and forecasts for natural gas production in the U.S. and imports from traditional supply sources such as Canada.

Figure 3-4
Natural Gas Demand Increases by Region
2002-2012
(Bcf)



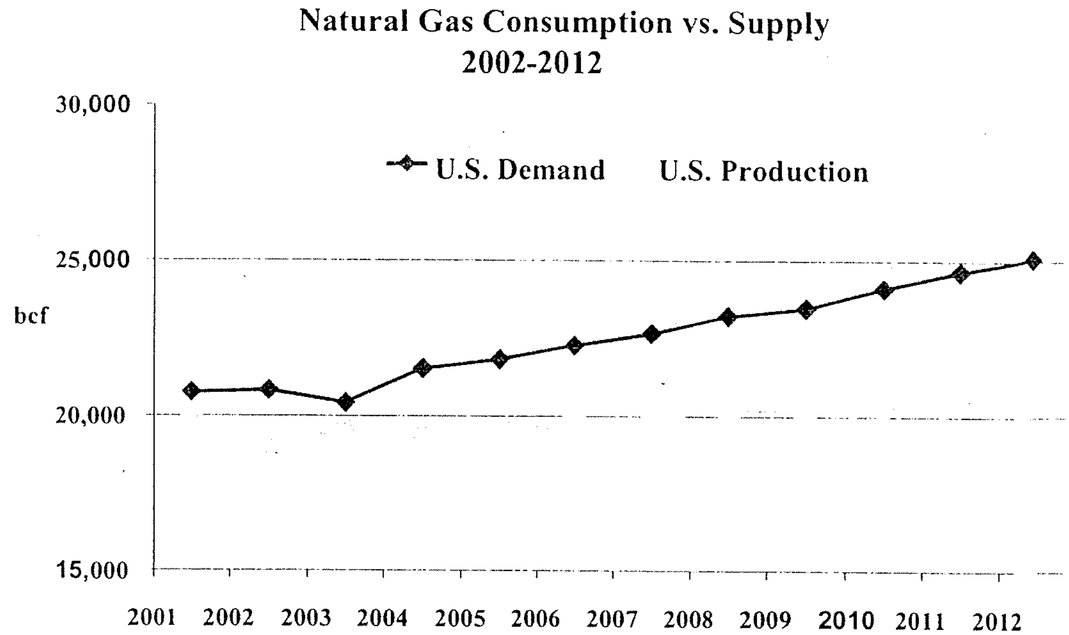
Source: EIA, AEO 2004

The EIA's 2004 Annual Energy Outlook provides a good overview of U.S. natural gas demand by region. Figure 3-4 shows that natural gas demand in every region of the country is projected to grow between 2002 and 2012. In the East, the largest increase in consumption is expected in the East North Central region and the Mid-Atlantic.[52] Hence, New England will compete with other gas consuming regions for available natural gas supplies. In order to receive supplies, prices in New England will need to be higher to draw gas supplies away from these other demand areas.

Another factor that may impact New England's natural gas supplies is the forecast of decreasing U.S. natural gas production. Figure 3-5 depicts the EIA's forecast of U.S. production relative to demand.

[52] According to EIA, differences in the projected growth for various regions result from different prospects for population growth, economic activity, and electricity generation.

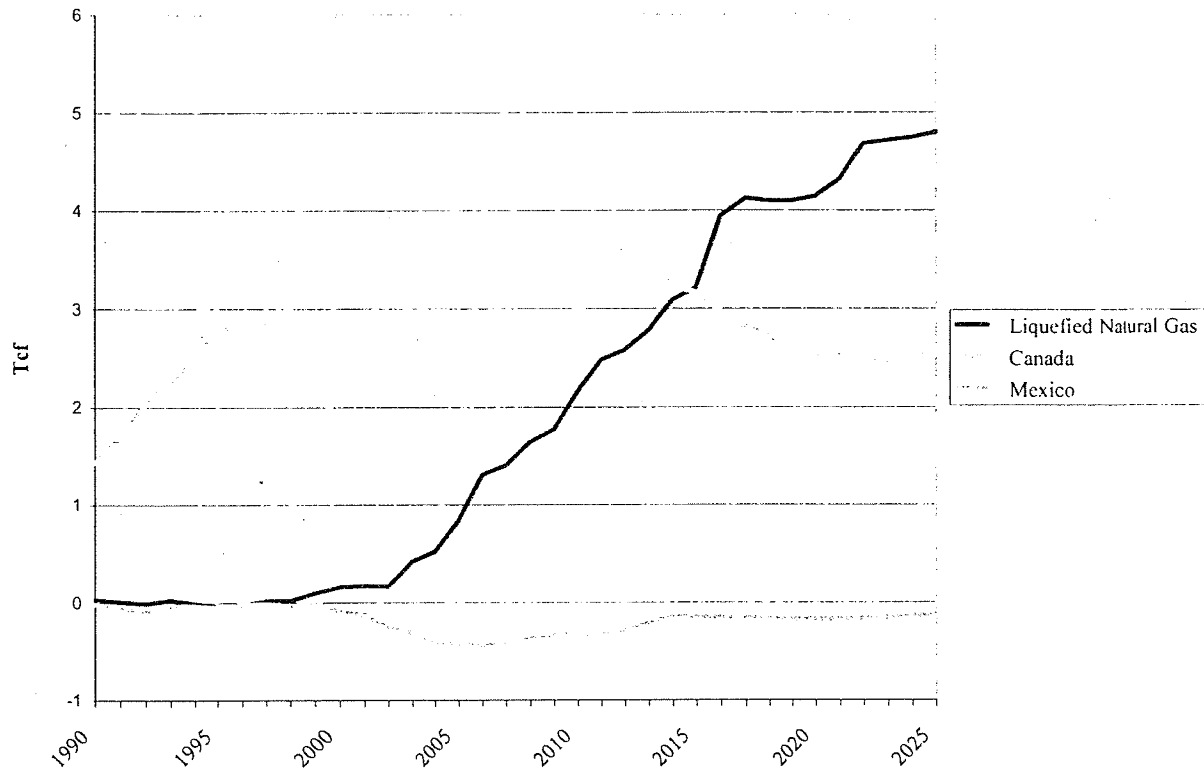
Figure 3-5



Source: EIA, AEO 2004

Since U.S. natural gas production alone cannot meet forecast demand, natural gas imports will have to make up the difference. EIA predicts that much of the imports will be LNG, since Canadian imports are also expected to decrease and imports from Mexico are estimated to remain flat. Figure 3-6 uses EIA data showing the projected imports.

Figure 3-6
Net U.S. Imports of Natural Gas
1990-2005



Source: EIA AEO 2004

Conclusion

Overall, New England's natural gas demand is growing, though not as fast as some forecasters have suggested. As a result, the demand/supply balance, given no drastic contingencies, does not reach dangerously close levels, as some forecasters have estimated, until after 2012. All sources, however, agree that the amount of New England's electric generation that will use natural gas as a fuel, on an annual average basis, is rapidly growing. Compared to the amount of gas needed for space heating on these days, the portion of natural gas supply used for electric generation on a peak demand winter day is about 23%[53] of total demand.

Under extreme conditions, natural gas will be diverted from electric generation to space heating needs. The space heating load that is delivered by gas utilities is protected by "firm" delivery contracts, whereas electric generators largely hold non-firm contracts that allow them to take gas only

[53] See Table 3-4, electric generation natural gas demand vs total natural gas demand.

after firm customers have been served. Even so, there are remedial strategies that have been and can be implemented to insure the reliability of the electric system on these peak demand days.

In general, the report finds that the region's existing gas delivery infrastructure (pipelines and storage mechanisms), will be able to meet peak day demands for gas for space heating and electric generation, at least through 2010. However, this is the case only if the region has continued use of the Everett LNG delivery terminal and the LDCs' satellite LNG facilities located around the region. Those facilities must have sufficient LNG in storage and be able to turn it into gas vapor and inject it into the LDCs' distribution pipeline system on those peak demand days. In an extreme case, if LNG from these facilities were not available on a peak day (e.g. because extremely cold weather for many days in a row had drained them down) the region could well have insufficient gas supply to meet the needs of all customers for space heating.

Even assuming this LNG storage and vaporization capability remains available, if gas demand grows at a rate equal to or higher than recent growth rates, the region's gas delivery infrastructure would be insufficient to deliver all needed gas after 2010. Under these conditions, to avoid leaving some customers without gas for space heat in 2010 and after, additional gas supply infrastructure (either expanded pipeline capacity or expanded LNG storage capacity) or resources that reduce gas demand would have to have been added to the system. Infrastructure expansions or demand reductions would have to be planned and started well before 2010 to help match supply with demand by 2010.

Beyond the ability of infrastructure to deliver gas supplies, sound energy policies also should contribute to achieving the lowest possible long run average price for the fuel and to maintaining as much stability as possible in the short-term price of that fuel. Policy-makers also must be concerned with the environmental and societal impacts of various fuel use scenarios. In the following chapter, several scenarios that might be pursued to address the goals of reliability of supply, price moderation and other impacts are examined.